ACCESSION #: 9606190289

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Calvert Cliffs, Unit 2 PAGE: 1 OF 8

DOCKET NUMBER: 05000318

TITLE: Unit 2 Reactor Trip Due to Power Excursion After Increase

in SG Levels

EVENT DATE: 01/15/95 LER #: 95-003-01 REPORT DATE: 06/14/96

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 2 POWER LEVEL: 4

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER:

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COMPONENT FAILURE DESCRIPTION:

CAUSE: SYSTEM: COMPONENT: MANUFACTURER:

REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On January 15, 1995, at approximately 0246, Calvert Cliffs Unit 2 tripped due to a Reactor Protective System loss of load signal. The loss of load signal was generated after power increased from 4 percent to 13 percent and the turbine was not on-line. The power excursion occurred after problems were experienced in controlling 22 Steam Generator Feed Pump (SGFP) and a rapid increase in steam generator levels resulted in a cooldown of the Reactor Coolant System.

The causes of the event are related to human performance. Areas determined to be less than adequate included operator experience and knowledge related to SGFP control;

decision making with respect to operating 22 SGFP; work practices including pre-evolution briefings and communication; procedural adherence; and reactivity management.

Short-term corrective actions were completed prior to startup and additional long-term corrective actions have been implemented.


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I. DESCRIPTION OF EVENT

On January 15, 1995, at approximately 0246, Calvert Cliffs Unit 2 tripped due to a loss of load. At the time of the event, the Main Turbine was not on-line thus a Reactor Protective System (RPS) loss of load trip signal was generated when reactor power increased from 4 percent to 13 percent power. This increase in power occurred after a large influx of water was introduced to the Steam Generators (SGs) from 22 Steam Generator Feed Pump (SGFP), causing a cooldown of the Reactor Coolant System (RCS).

At around 0200 on Sunday, January 15, 1995, during the startup of Unit 2 following a trip on January 13, 1995, licensed utility operators began preparations to place Calvert Cliffs Unit 2 SGFPs on main steam. Reactor power was at 4 percent and in accordance with Operating Procedure (OP)-2, the SGFPs were required to be shifted over from auxiliary steam to main steam prior to entering MODE 1 (5 percent power). A pre-startup brief was held at the beginning of the shift to discuss startup activities, including the need to shift steam supplies for the SGFPs. As the evolution began, 22 SGFP was in-service feeding the SGs and being supplied from auxiliary steam; 21 SGFP was not in-service at the time.

In accordance with Operating Instruction (OI)-12A, operators attempted to start 21 SGFP on main steam. Pump speed is usually controlled with an automatic system that uses a Hand Indicator Control (HIC). The pump can also be controlled in the Control Room at the Operator Control Station (OCS) in a manual mode or by directly opening and closing the SGFP governor valves. Each SGFP has Low Pressure (LP) and High Pressure (HP) governor valves that control the admission of steam to the pump's turbine. LP steam from either the auxiliary boilers or reheat steam system is supplied to the LP governor valves while main steam is supplied to the HP governor valve. The LP valves are poppet valves that ramp open. When the LP valves are nearly full open the HP valve will start to open.

On January 15, a dedicated Control Room Operator (CRO) was assigned to control feedwater during the startup. Using OI-12A, the CRO instructed the Turbine Building operator (TBO) to align 21 SGFP for main and reheat steam. The CRO then reviewed a procedurally controlled Temporary Note attached to control panel 2CO3 that described a problem with the HIC and OCS manual control for 21 SGFP. The problem was identified in October and an Issue Report had been written to correct the problem during the upcoming Unit 2 Refueling outage scheduled for March, 1995. The Temporary Note stated the pump should be controlled using direct governor valve control. Although the use of direct governor valve control is described in OI-12A, it is used infrequently. After approximately 45 minutes of attempting to start 21 SGFP



using direct governor control, operators determined an unknown problem existed with the system and ceased efforts to start the pump.

Although it is desirable to have both SGFPs, the plant can be started with only one SGFP in-service. After attempts to start 21 SGFP were unsuccessful, the Shift Supervisor elected to proceed with the startup using 22 SGFP. Both the Shift Supervisor and a Senior Reactor Operator (SRO) dedicated to support the startup did not think shifting 22 SGFP from auxiliary steam to main steam would be difficult. Section 6.19 B 2 of OI-12A contained guidance on shifting the pump from auxiliary steam to main steam. A TBO and helper were dispatched to the 121 elevation of the Unit 2 Turbine Building to align 22 SGFP to main steam and to operate the auxiliary steam supply valve, O-AHB-221. The intent of the procedure is to slowly throttle O-AHB-221 closed while maintaining pump speed. As the valve is throttled closed the LP governor valves will open further in response to the lower steam flow, in order to maintain pump speed. Once the LP governor valves are nearly fully open the HP governor will start to open and eventually pump speed will be controlled on main steam with O-AHB-221 fully closed. A note within OI-12A states, "O-AHB-221 is slowly shut to allow 22 SGFP Governor Valve sufficient time to respond to the reduced steam flow, The SGFP Governor Valve will take several minutes to respond to each adjustment of O-AHB-221."

The directions to the TBO from the CRO were to align 22 SGFP to main steam and to call once the helper started to shut O-AHB-221. The TBO had the procedure in hand and was responsible for monitoring pump speed and communicating with the Control Room. As the helper began to shut O-AHB-221 the speed of the pump dropped from about 3200 rpm to around 1100 rpm. The TBO then called the CRO and relayed his concern about the abrupt drop in pump speed. The CRO expected speed to drop and directed the TBO to fully shut O-AHB-221. The CRO wanted to control the pump with main steam so he swapped 22 SGFP from HIC control to OCS manual control and in accordance with OI-12A, changed the gain setting on the OCS to the main steam supply. At this point levels in the SGs were decreasing and the speed of the pump was not increasing. The CRO believed main steam was controlling the pump but did not understand why the pump would not respond to his manipulations in OCS manual. The CRO asked the TBO to reverify the main steam alignment, and with 22 SGFP's speed at about 1000 rpm, directed the TBO to reopen O-AHB-221.

The TBO rapidly opened O-AHB-221 several turns then partially closed it to limit 22 SGFP's speed to about 2000 rpm. With the pump's speed rising, the CRO believed main steam was now controlling the pump and he directed the TBO to close O-AHB-221 again. Once again, the speed of the pump dropped and SG low level pre-trip alarms started to come in. In response to low levels in the SGs, Abnormal Operating Procedure (AOP)-3G was entered and 23 Auxiliary Feedwater (AFW) Pump was started. With 22 SGFP's speed at around 1000 rpm, the CRO directed the TBO to slowly open O-AHB-221 all of the way. After the TBO opened O-AHB-221 about half way pump speed increased rapidly to around 4000 rpm. In response to the increased feed from 22 SGFP, levels in the SGs rapidly increased. The dedicated CRO attempted to lower the levels by lowering the SG level setpoint in the automatic feedwater control system and by attempting to lower SGFP speed in OCS manual. After seeing no response in OCS manual he swapped over to HIC control and the pump speed decreased to 3600 rpm.

The approximately 68 inch increase in SG levels caused a 17 degree Fahrenheit decrease in RCS temperature and a decrease in RCS pressure. The Shift Supervisor noted the temperature decrease and stated the reactor would be tripped manually if temperature decreased to 515 degrees Fahrenheit. This decrease in temperature resulted in a reactor power increase due the effects of a large negative end-of-life Moderator Temperature Coefficient (MTC). Additionally, the Reactor Operator (RO) assigned to monitor temperature and pressure raised the Control Element Assemblies (CEAs) when RCS temperature dropped, thus contributing to the reactor power increase. The power increase due to CEA withdrawal was later determined to be minor compared to the RCS cooldown. Reactor power increased to about 13 percent whereupon a RPS loss of load trip occurred since the main turbine was not on-line. Seconds before the automatic reactor trip occurred the Shift Supervisor ordered a manual trip due to low RCS temperature.

II. CAUSE OF EVENT

In response to this event, the Plant General Manager established an event investigation team to determine the cause(s) of the event and to recommend corrective actions. The investigation team has concluded the following causes were associated with this event:

A. The operators' knowledge and experience in operating the SGFPs under certain modes of control was lacking. When 21 SGFP could not be started because of problems with the HIC and OCS manual control, the operators were forced to use the direct governor valve mode of control in accordance with the Temporary Note. Their inexperience in using this form of pump control resulted in the failed attempts to start the pump. Additionally, the operators involved were inexperienced in shifting the SGFP's steam supply from auxiliary steam to main steam on a pump that is currently feeding the steam generators. This is a very infrequent evolution and a digital feedwater modification made in 1993



lengthened the time required to shift steam supplies. This evolution is not specifically covered in training.

B. Decisions made by the operators in this event were less than adequate. After 21 SGFP could not be started a decision was made by the Shift Supervisor to proceed with the startup using only one SGFP. It is not uncommon to startup the plant with one SGFP, but as mentioned above, in this case the operators were inexperienced in performing the task under the conditions present at the time.

Before and during the event, there were opportunities to assess the condition of 22 SGFP, and discuss the risks associated with starting the unit with 22 SGFP.

C. Work practices associated with this event were less than adequate. Although a pre-startup brief was held at the beginning of the shift to discuss the plan for startup, there was no specific pre-evolution briefing for placing the SGFPs on main steam. The operators did not view this task as being difficult because they were unaware of the effect the digital feedwater modification had on the time required to shift steam supplies. Thus, the operators did not hold a specific briefing to discuss the task or review the procedure. Additionally, the dedicated feedwater CRO did not use adequate self-verification by reviewing the steps in OI-12A with the TBO prior to directing him to shift the steam supplies. Communications between the dedicated CRO and TBO were less than adequate with respect to discussing key parameters like pump speed and valve position prior to closing O-AHB-221.

D. Procedure adherence in this event was less than adequate. Section

6.19 B.2.f. of OI-12A specifically directs the operator to throttle O-AHB-221 shut while maintaining the speed of the pump. As explained above, as less auxiliary steam is supplied to the pump, main steam will be supplied to maintain pump speed. When the CRO directed the TBO to close O-AHB-221 the first time, pump speed was not being maintained as required by the procedure. As stated above, the CRO thought main steam was controlling the pump but he did not ensure speed was being maintained as required. An opportunity to challenge the CRO decision was missed when the TBO failed to question the CRO after being told to shut the valve all the way.

E. Reactivity management by the RO, dedicated SRO, and Shift Supervisor was less than adequate. The increased feed to the SGs was not recognized by the dedicated SRO or Shift Supervisor as a precursor to a reactor power excursion. They were not sensitive to the fact that the cooldown would quickly increase reactor power due to the end-of-



life high negative MTC. Additionally, the RO focused on the low RCS temperature and inappropriately pulled CEAs in response without monitoring reactor power during the CEA motion. It was determined after the event that the pulling of CEAs added very little reactivity compared to the effects of the MTC.

III. ANALYSIS OF EVENT

After 22 SGFP picked up speed, levels in the SGs increased resulting in a cooldown of the RCS. The RCS cooldown added positive reactivity to the reactor core. The RO also added reactivity when he pulled CEAs in response to the RCS temperature decrease, but this amount of reactivity was minor compared to that added by the cooldown. The positive reactivity addition resulted in reactor power increasing from 4 percent to 13 percent, whereupon the reactor tripped due to a loss of load signal from the RPS.

The safety consequences of this event are bounded by the Control Element Assembly Withdrawal Event analyzed in Chapter 14 of the Calvert Cliffs Updated Final Safety Analysis Report. The analysis does not credit the RPS loss of load trip but does credit the RPS Variable High Power Level trip at 40 percent power in preventing design limits from being exceeded.

This event is considered reportable under 10 CFR 50.73 (a)(2)(iv), as an event that resulted in the automatic actuation of any engineered safety features including the RPS.

IV. CORRECTIVE ACTIONS

Prior to restarting Unit 2, the following corrective actions were taken:

A. The Superintendent-Nuclear Operations and General Supervisor-Nuclear Plant Operations briefed each operations crew on the event prior to assuming their watch after the event and emphasized their expectations relative to procedural adherence, decision making, reactivity management, work practices, communications, and maintaining a questioning attitude. New expectations for the performance of infrequent evolutions and evaluating equipment problems were established. The Plant General Manager also participated in the briefing. To reinforce these expectations, Operations Management provided on-shift start-up coverage.

B. System Engineering assistance for SGFP control was provided and will be used during future startups until additional operator training is completed. The General Supervisor-Nuclear Plant Operations also put



in place a policy that requires his notification prior to starting the plant up on one SGFP.

C. Both 21 and 22 SGFP were thoroughly tested to determine if any mechanical malfunctions existed and contributed to the event. The problem identified in October, 1994, with the 21 SGFP HIC and OCS manual control was corrected. The procedure for shifting steam supplies on a SGFP in service was changed to require Superintendent-Nuclear Operations or General Supervisor-Nuclear Plant Operations permission prior to use.

D. The qualifications of the operators involved with the event, with respect to decision making and reactivity management, were evaluated by Operations Management. Appropriate personnel actions and remedial training were implemented.

The following long-term corrective actions have been taken:

A. Additional plant simulator and classroom training was provided to plant operators to improve their proficiency on the feedwater control system during normal, abnormal, and start-up operations. our initial operator and requalification training programs have been revised to include similar feedwater controls system training.

B. Operating Procedures (OP)-2, "Plant Startup From Hot Standby to Minimum Load," OP-4, "Plant Shutdown From Power Operation to Hot Standby," and Abnormal Operating Procedure (AOP)-3G, "Malfunction of Main Feedwater System," were revised to include cautions for the effects of reactivity additions from excessive feeding at low power operations.

V. ADDITIONAL INFORMATION

A. Failed Component Identification

Not applicable.

B. Previous Similar Events

There is one previous similar event at Calvert Cliffs Unit 1 in which high SG levels resulted in a cooldown of the RCS and an increase in reactor power. As reported in LER 87-11, on July 14, 1987, control of 16A high pressure feedwater heater water level was lost, reducing heat transfer to the SG feedwater. The cooler feedwater caused a reduction



in RCS temperature leading to an increase in reactor power, due to a negative MTC. At the time of the event, power was 100 percent and

increased high enough to pickup the high power pre-trip alarm. The

RO on duty was directed to borate the RCS and insert CEAs. Reactor

power dropped faster than turbine power could be reduced, resulting

in a high SG level trip. The corrective actions from this event

dealt with malfunctions experienced in the boration and feedwater

heater systems and are not applicable to the event that occurred on

January 15, 1995.

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BGE

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June 14, 1996

U.S. Nuclear Regulatory Commission

Washington, D.C. 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant

Unit No. 2; Docket No. 50-318; License No. DPR 69

Licensee Event Report 95-003, Revision 1

Unit 2 Reactor Trip Due to Power Excursion After Increase in SG Levels

The attached report is being sent to you as required under 10 CFR 50.73 guidelines. Should you have any questions regarding this report, we will be pleased to discuss them with you.

Very truly yours,

PEK/RCG/bjd

Attachment

cc: D. A. Brune, Esquire

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